Integrated Resource Planning

ROUNDTABLE 22-4

APRIL 2022

MEETING LOGISTICS

Electronic version of presentation:

https://www.portlandgeneral.com/our-company/energy-strategy/resource-planning/integrated-resource-planning/irp-public-meetings

Teams Meeting:

Please click the meeting link sent to your email and here:
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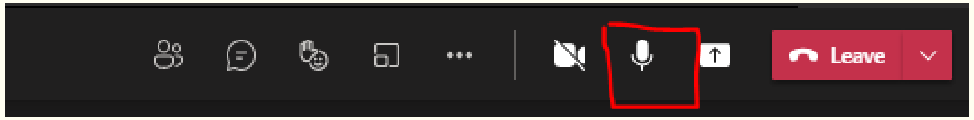
-OR-

Call this number on your phone:
+1 971-277-2317
Conference ID: 508 941 354#

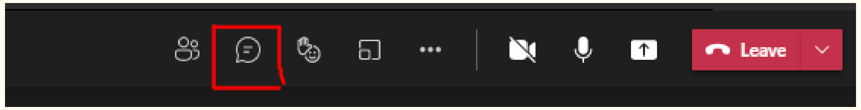
*Please use *Microsoft Edge* or *Google Chrome* for the best experience.

PARTICIPATION

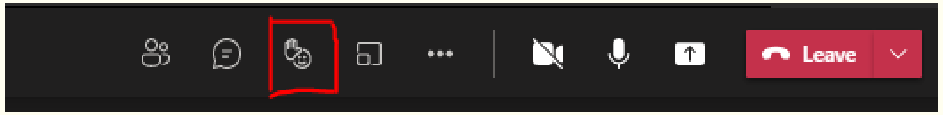
- Mute your mic while others are speaking; to unmute via phone press *6



- We will ask for comments and questions along the way
- Participate using the chat box or ask questions verbally



- Use the “raise hand” feature to signal you would like to ask your question verbally



- Wait to be called on
- Please be polite and respect all participants on the webinar
- Please stay on topic; we may interrupt or shorten questions to meet the time commitment of the meeting

AGENDA

Welcome and Introductions	8 minutes
Safety Moment	2 minutes
High Level 2023 IRP Schedule	10 minutes
Solar Inverter Loading Ratios	15 minutes
GridPath Flexibility Analysis	15 minutes
Climate Adaptation Study	15 minutes
Final Load Forecast	25 minutes
RPS Modeling	10 minutes
Price Update	10 minutes

This presentation is being recorded

SAFETY MOMENT

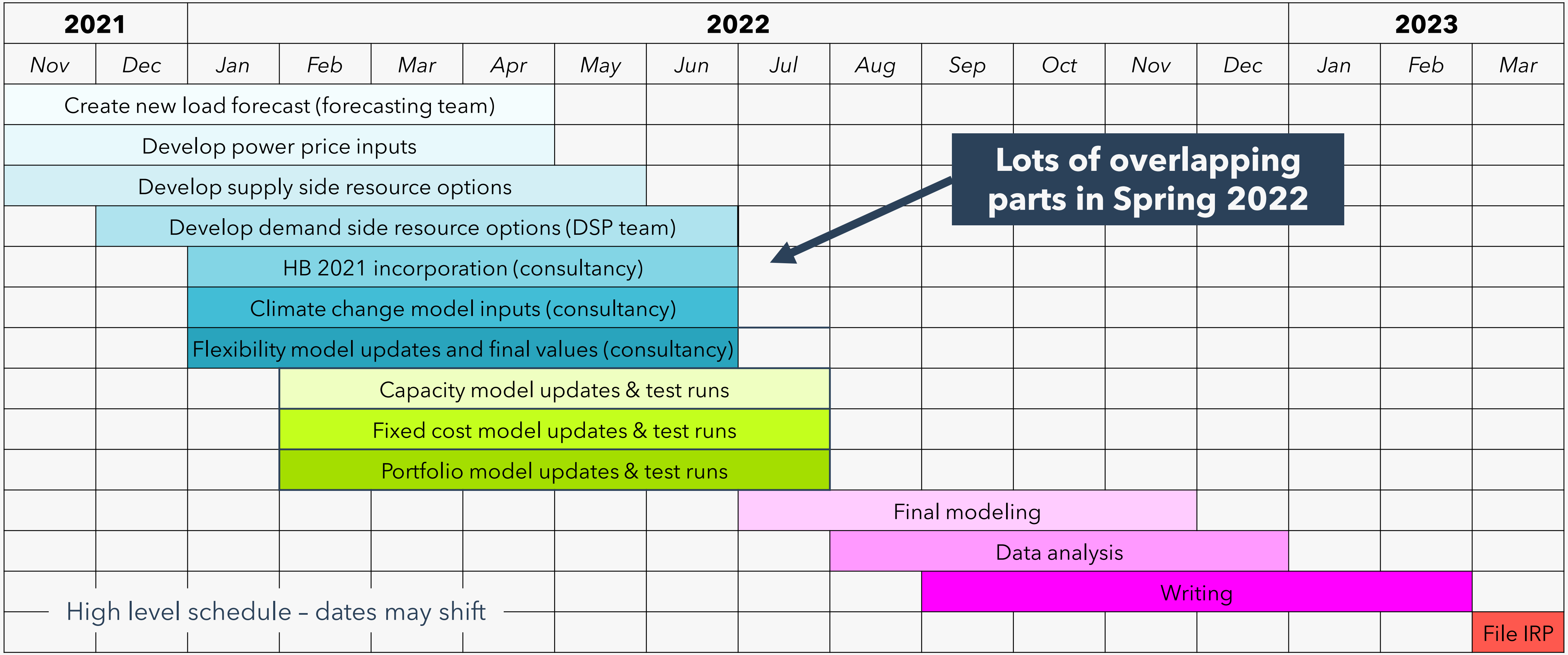
Spring Safety Tips

Spring outdoor work: Think about ladder safety and inspect your tools before you begin outdoor projects.

Slips, trips, and falls: Softer ground or muddy conditions can be hazards in the spring weather; wear weather/work appropriate shoes and watch your step.

Changeable weather: Be prepared for dry, wet, warm, and cold weather by taking extra care with your attire and supplies.

HIGH LEVEL 2023 IRP SCHEDULE



SOLAR INVERTER LOADING RATIOS

TOMÁS MORRISSEY

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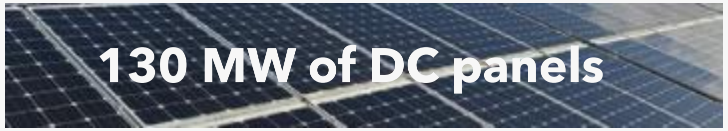
PGE

Inverter Loading Ratio Basics

Ratio of panels (DC) to inverter (AC) size

- For example, if 130 MW of panels are paired with a 100 MW inverter, the ratio is 1.3



+ **100 MW AC inverter** = **100 MW solar project with a 1.3 ILR**

Higher ratios allow for higher/smoother solar production

- Generating more both when sun is setting/rising and with clouds
- Once system is at 100% in an hour, going to a higher ratio won't be beneficial in that hour
  - *For example, if a 100 MW 1.2 ILR facility is producing 100 MW of solar at 1 PM in June, increasing the ILR won't increase generation in that hour since the inverter is already maxed out. It likely will increase generation where the project is not at 100%.*

Inverter Loading Ratios in NW IRPs

Source	**Value**	**Notes**
PacifiCorp 2021 IRP	1.30	**Reduced from 1.46 in prior IRP based on industry trends** - page 191
Puget Sound Energy 2021 IRP	1.20	"All solar resources were modeled with a DC to AC ratio of 1.2" - page 55 appendix D
Idaho Power 2021 IRP	1.30	Discussed in February 2022 UM 2022 PUC Staff meeting
PGE Proposed 2023 IRP value	1.34	Proxy resource based on 2020 Q1 NREL study
NWPCC 2021 Power Plan	1.40	Samples a range of IRPs/studies – **only source above 1.3 is PAC from 2019 IRP**

NREL PV Benchmark Sees ILR Drop

Table 11. LCOE (Stand-Alone PV) Input Assumptions and Outputs (2020 USD)

	Residential		Commercial Rooftop		One-Axis Tracker	
	2020	**2021**	**2020**	**2021**	**2020**	**2021**
Installed cost ($/W)	2.74	2.65	1.74	1.56	1.02	0.89
Annual degradation (%)	0.70	1.00	0.70	0.70	0.70	0.70
Levelized O&M expenses over life of asset ($/kW-yr)	29	29	19	18	18	16
Preinverter derate (%)	90.5	85.9	90.5	85.9	90.5	85.9
Inverter efficiency (%)	98.0	96.0	98.0	96.0	98.0	96.0
Inverter loading ratio	1.15	1.15	1.15	1.15	1.34	1.28
Inflation rate (%)	2.5	2.5	2.5	2.5	2.5	2.5
Equity discount rate (real) (%)	6.1	10.2	6.1	6.1	5.1	5.1
Debt interest rate (%)	5.0	4.5	5.0	5.0	5.0	5.0

NREL: U.S. Solar Photovoltaic System and Energy Storage Cost Benchmark: Q1 2021 (report was published in November 2021; 1.34 value out of an older version of the report published in January 2021).

ILR & Christmas Valley Solar

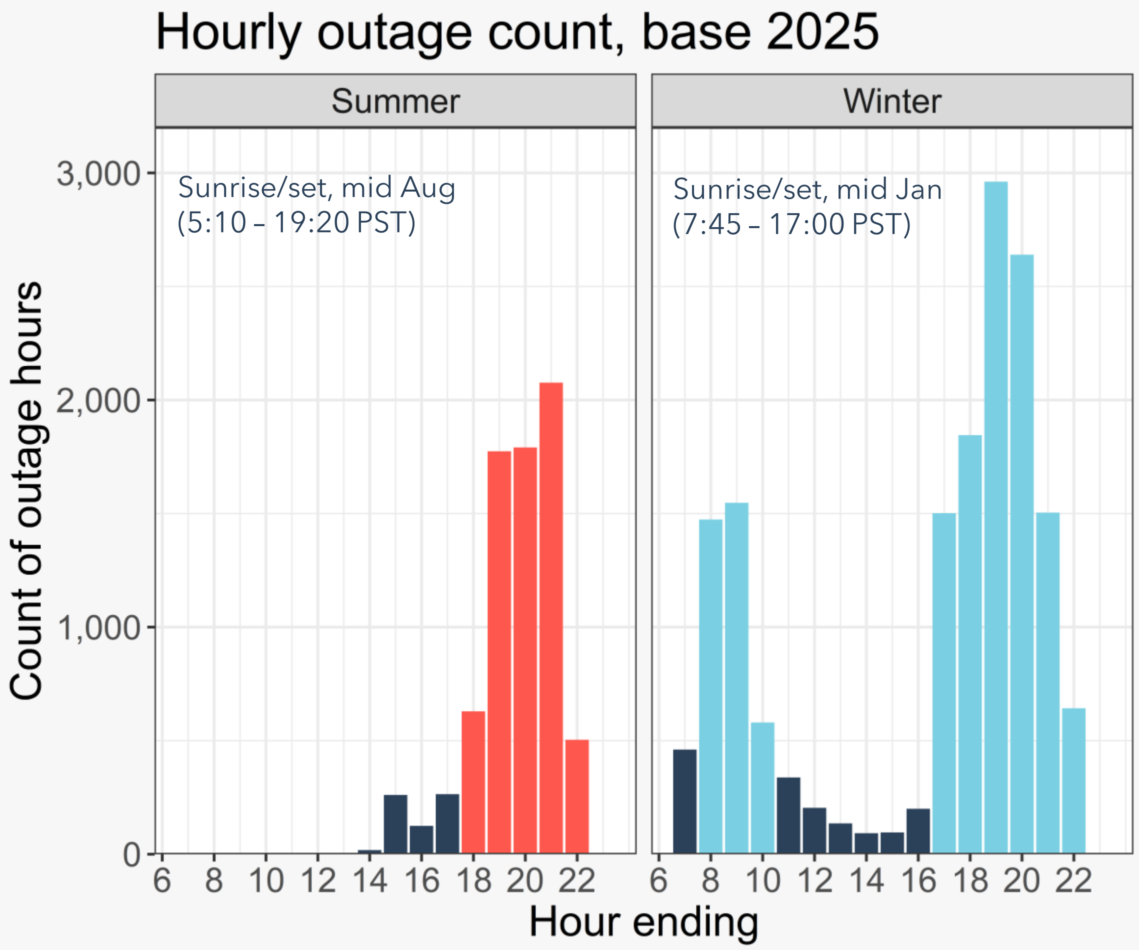
Next slides will focus on Christmas Valley solar at three ILR ratios:

a) 1.34
b) 1.50
c) 1.70

Most Outages Occur in Evening/Night

Graph shows when outages are occurring in the model, highlight added to hours with over 500 outages (50,000 weeks simulated for year 2025).

Most outages occur at evening/night.

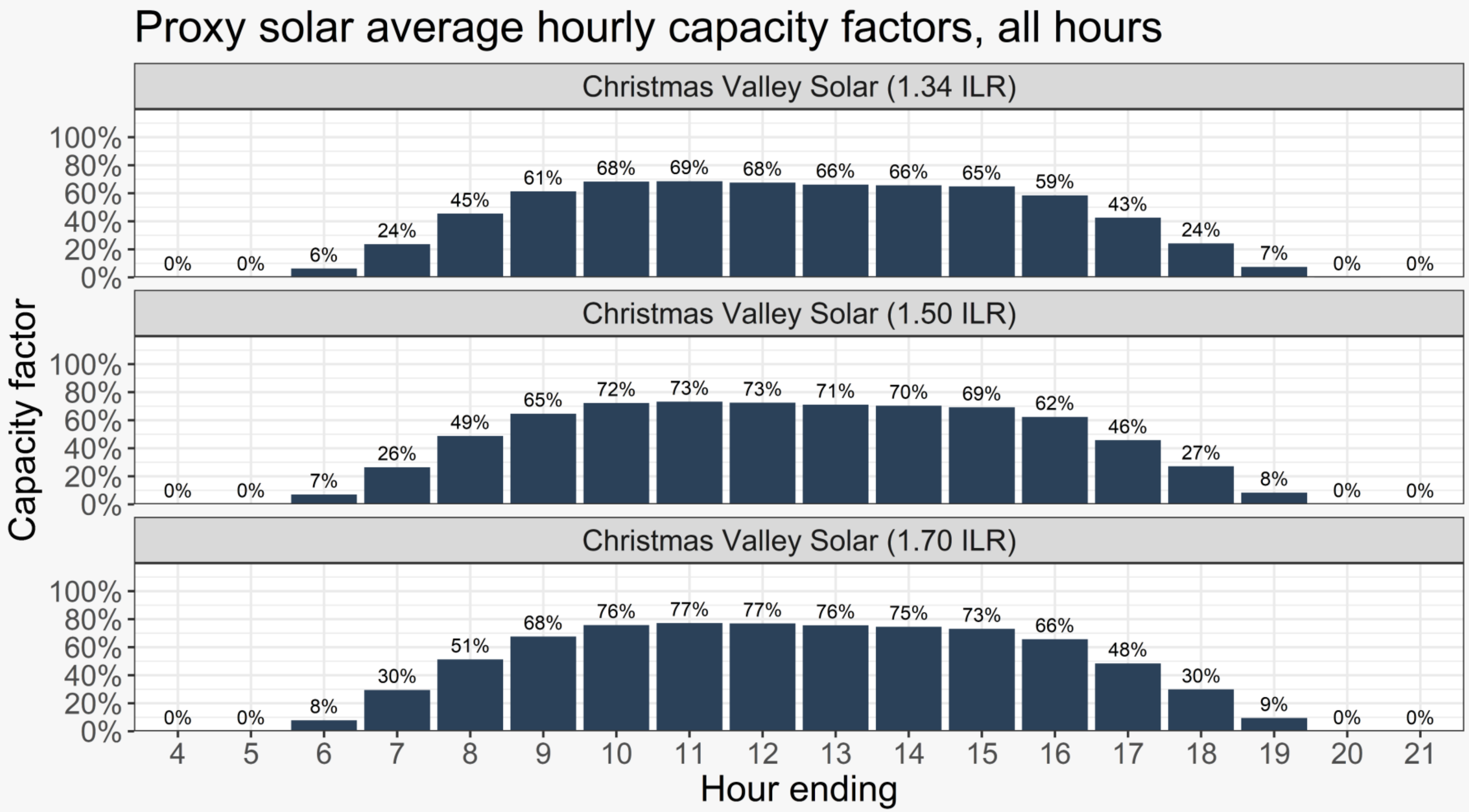


Values from Case One with no new solar additions.
Summer is Jul – Sep; Winter is Nov – Feb.

Christmas Valley Solar, Annual ILR Comp

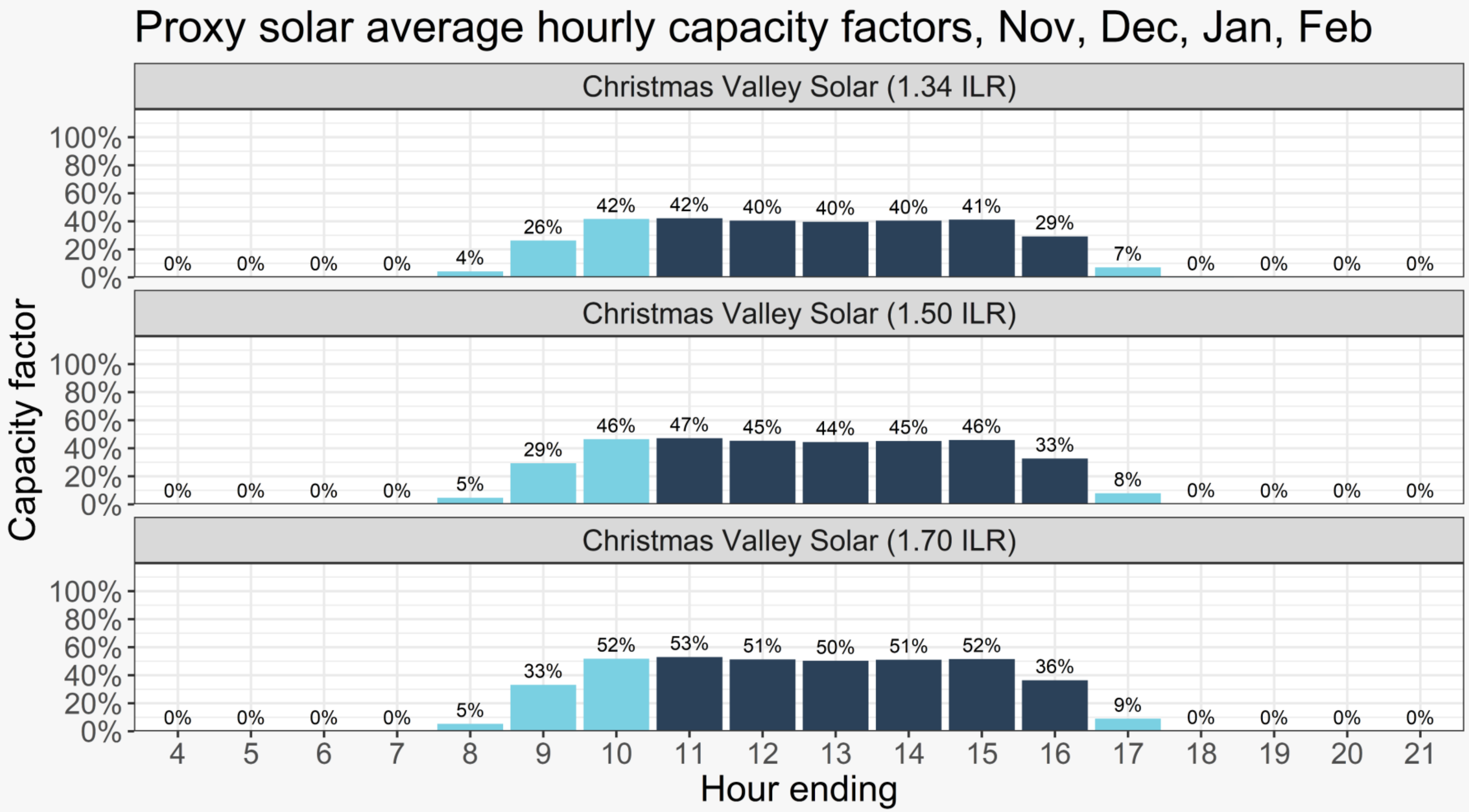
Annual CF:

28% at 1.34 ILR
30% at 1.50 ILR
32% at 1.70 ILR



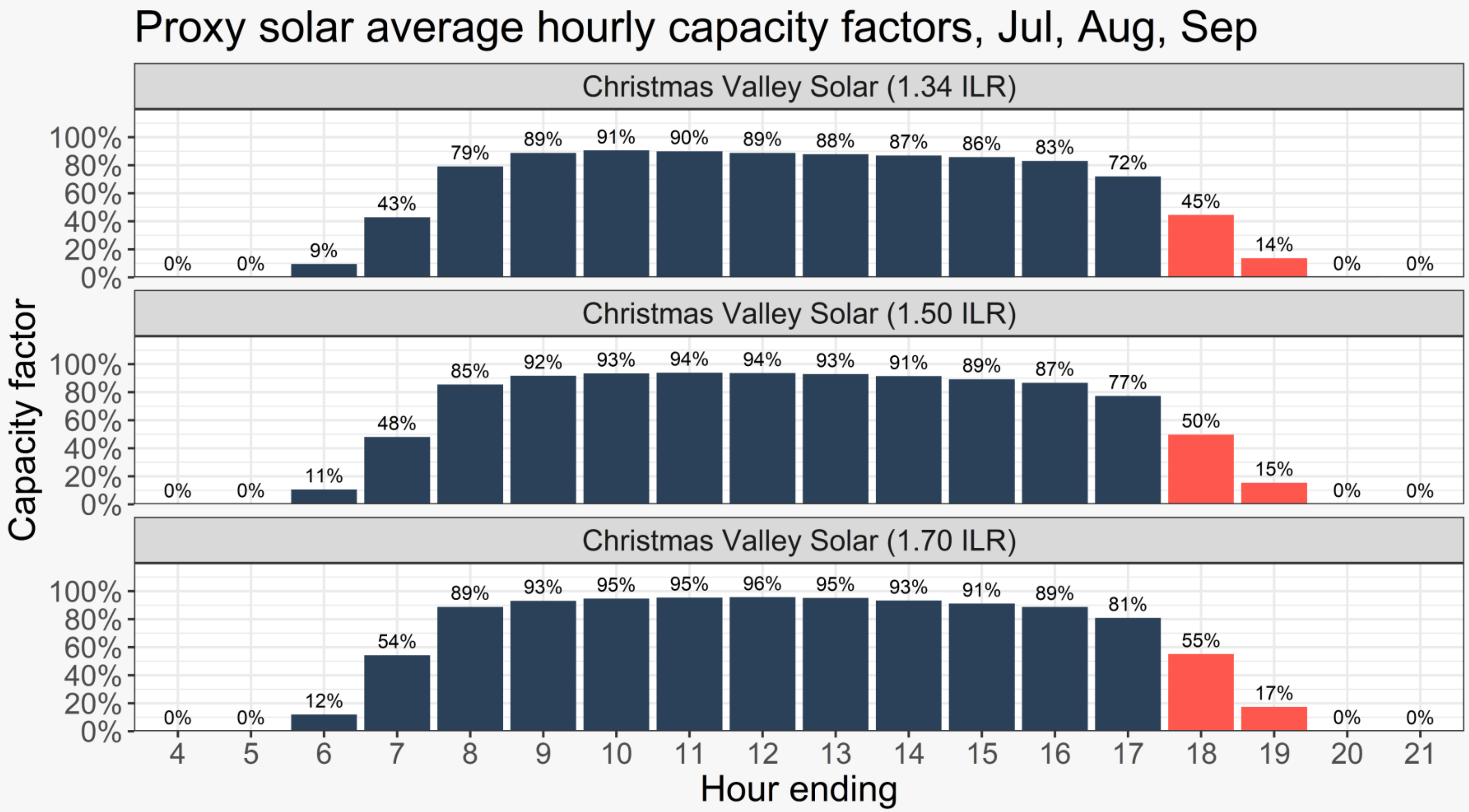
Christmas Valley Solar, Winter ILR Comp

Highlight on hours with over 500 outages (from adequacy model)



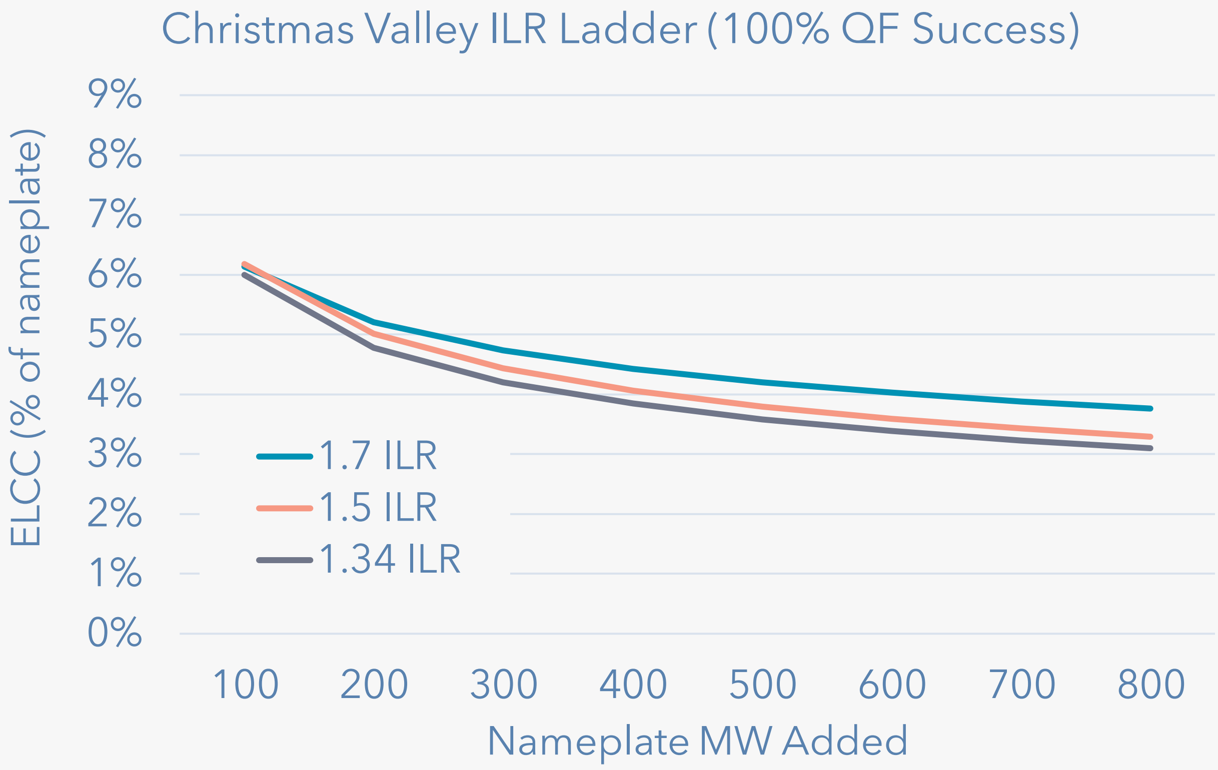
Christmas Valley Solar, Summer ILR Comp

Highlight on hours with over 500 outages (from adequacy model)



ELCC and ILR in PGE's 2025 System

ELCC change from higher solar ILR under one percentage point across different resource size additions



For 2023 IRP

We plan to use an inverter loading ratio of 1.34 for solar projects in 2023 IRP

- At high end for Northwest IRPs
- Recent trend towards lower ratios seen in PacifiCorp's 2021 IRP and 2021 NREL report ("U.S. Solar Photovoltaic System and Energy Storage Cost Benchmarks")
- PGE was asked by PUC Staff and stakeholder to use public data for resource assumptions (1.34 ILR comes from public NREL report)
- Move to an ILR above 1.34 has minimal impact on capacity in PGE system model

GRIDPATH FLEXIBILITY ANALYSIS

ANA MILEVA – *BLUE MARBLE ANALYTICS*

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Blue Marble Analytics creates innovative, high-quality grid analytics software to guide clean energy planning and policy.

We provide consulting and software-development services for power-system planning and portfolio optimization and management.

Blue Marble
Analytics

Ana Mileva is the founder of Blue Marble Analytics and the primary architect of the GridPath platform. Previously a consultant at E3, Ana was the lead developer of the RESOLVE model, now used widely for resource planning. She has wide-ranging experience consulting for utilities, government agencies, NGOs, and developers.

Experience in the last two PGE IRPs

- 2016 IRP: led capacity-adequacy and reliability study (E3)
- 2019 IRP: led flexibility adequacy analysis

Expertise across a range of topics including:

- Software development
- Data analytics
- Resource planning and portfolio optimization
- Asset optimization and valuation
- Renewables integration
- Storage, demand response, hybrid resources
- Clean energy policy

Flexibility Analysis Scope Overview

- A set of studies that aim to assess **flexibility needs, costs, and value**.
- Studies will be conducted using multi-stage optimal commitment and dispatch in **GridPath**, an open-source grid planning platform.

Flexibility Adequacy

This component seeks to model flexibility adequacy and evaluate how different resources contribute to it.

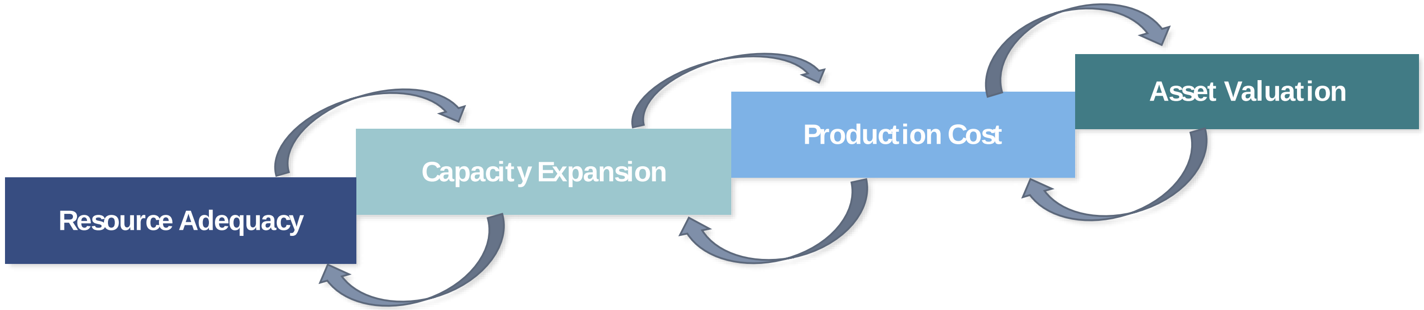
Variable Energy Resource (VER) Integration Costs

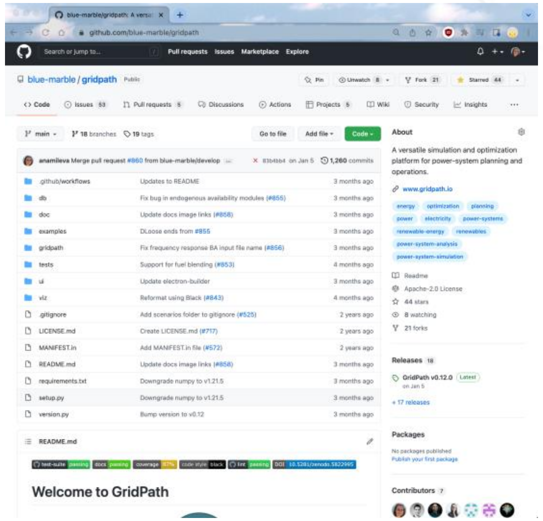
This component estimates the costs of integrating additional VREs into the PGE system.

Flexibility Value

This component evaluates the value of flexibility provided by different resources such as energy storage, flexible loads, or gas generators.

GridPath is an open-source modeling ecosystem that enables faster and more technically sophisticated planning for the clean energy transition.



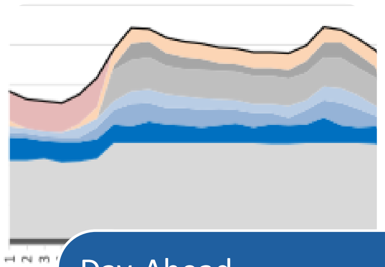


GridPath's modular architecture enables:		
A seamless interface between different modeling approaches Reduces the labor-intensive data-translation requirements across applications	**Varying levels of complexity** User has flexibility to include or exclude features easily User-defined granularity levels for modeling	**Extensibility and adaptability** Novel functionality can be added quickly and seamlessly to tackle new questions about an evolving, decarbonizing grid

- Open-source codebase available at https://github.com/blue-marble/gridpath
- GridPath has been benchmarked against PLEXOS and RESOLVE

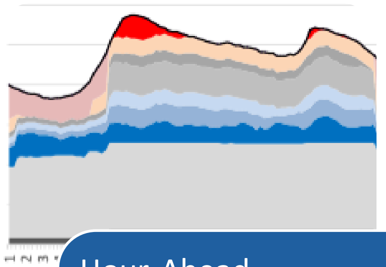
Production-Cost Simulation with GridPath

Multi-stage unit-commitment and dispatch with flexible temporal span and resolution



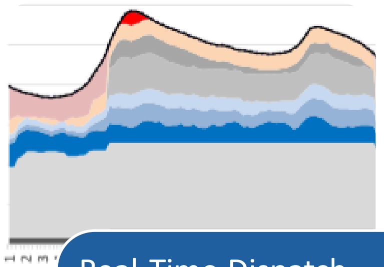
Day-Ahead Commitment

- Generator commitment schedules based on day-ahead load and renewable forecasts (e.g. hourly)
- Contingency, load-following, and regulation reserves



Hour-Ahead Commitment

- Residual generator commitment schedules based on hour-ahead load and renewable forecasts (e.g. 15-minute)
- Contingency, load-following, and regulation reserves



Real-Time Dispatch

- Actual load and renewable output (e.g. 5-minute)
- Contingency and regulation reserves
- Load-following reserves allowed to dispatch to compensate for net load forecast error

Generators can be modeled with a high level of operational fidelity

- Heat rate curves
- Minimum up and down times
- Ramp rates
- Start costs by cooling state
- Startup and shutdown trajectories

Includes fuel constraints, market availability, regulation, contingency, and load-following reserve requirements

Current Status

- Updates to GridPath implemented to accurately represent PGE generators and system
- Model is running with draft inputs
- Finalizing assumptions in coordination with IRP team
- Draft results in May

Thank You

Contact

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CLIMATE ADAPTATION STUDY

ANDRES ALVAREZ – CREATIVE RENEWABLE SOLUTIONS

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CRS Team

Creative Renewable Solutions

Over 100 Years Combined Experience in the Renewable Energy Space

Gerry Froese

Partner

Market Structures & Portfolio Optimization

Barrett Stambler

Partner

Renewable Origination & Policy

Andres Alvarez

Research Director

Power Modeling & Market Research

Dillon Stambler

Investments & Analytics Director

Renewable Structured Finance & Analytics

Jon Fischer

Transmission Strategy and Transactions Director

Transmission Strategy & Commercial Agreements

Jin Sun

Renewable Energy Project Finance & Analytics Intern

Power Market Research & Geospatial Data Analysis

What Are The Problems?

Climate Change	Resilience	The ability to recover from climate change-induced effects		
	Resource Adequacy	Available Generation	Hydro	• Runoff pattern, seasonal variability, precipitation pattern
			Wind	• Wind pattern and speed
			Solar	• Irradiance, ambient air temperature, module temperature
			Thermal	• Cool water discharge potential (quantity and temperature) • Capacity degradation due to extreme weather
			Nuclear	
			Forced Outage	• Fuel and supply disruptions, transmission disruption and facility damage under extreme weather conditions
		Loads	Peak load	• Heating and cooling demand under extreme weather conditions
			Average load	

[1] Source: https://climate.copernicus.eu/sites/default/files/2020-07/10-C3S_Energy_Symposium_Joyeau_May2020.pdf

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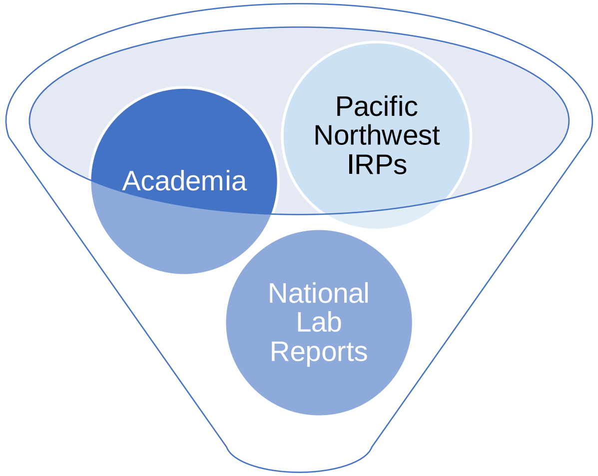
Method



Consolidate Studies and Impacts

RA Modeling Recommendations

PGE Sequoia

What are we trying to learn?

- What are the climate change impacts on generations, forced outages, and loads?
- What are the ranges of these impacts under different climate scenarios (IPCC RCPs)?

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Preliminary Results

Resource Adequacy	Available Generation	Hydro	• For the Pacific Northwest, studies generally predict reduced summertime generation potential, but they disagree as to whether annual generation will increase or decrease because of disagreement among hydrology models. • Historically, 10-year drought reduces hydroelectric generation by 26% in the Pacific Northwest [1] • Rising temperature will reduce annual hydropower generation by up to 8.2% in 2050 in California. [2]
		Wind	• Rising temperature is likely to decrease wind output in the central U.S. by 8%–10% but increase the generation in the east central U.S. by 2050. [3] • Wind generation potential may reduce by 40% in spring and summer months due to a 4-6% decrease in wind speed in Northwest U.S. [4]
		Solar	• Rising temperature is likely to increase solar output by 0-3% in southeast U.S. and decline the output by 0-3% in CA and northwest U.S. by 2049. [5]
		Thermal	• Climate change driven temperature changes in the Western US is likely to reduce the average summertime capacity of thermal facilities by 1.6-9.5% [6]
		Nuclear	• A rise in temperature of 1°C reduces the supply of nuclear power by about 0.5% through its effect on thermal efficiency; during droughts and heat waves, the production loss may exceed 2.0% per degree Celsius because of constrained cooling water system. [7]
		Forced Outage	• Combined cycle and combustion turbines can potentially experience much higher forced outage rates (15-20%) than what is typically expected (3%) during extreme cold periods. [8]
	Loads	Peak load	• Commercial buildings will see 5-10% increase in their peak load (MW), while residential buildings will see more than 10% increase in peak load by 2045 in Western U.S. [9]
		Average load	• In the Western US, Commercial and residential buildings will see a 2-8% increase in monthly summer load (MWh), due to increased AC usage. Autumn and Spring monthly load experience similar increase too. [9]

References

1. Analysis of Drought Impacts on Electricity Production in the Western and Texas Interconnections of the United States. C.B. Harto and Y.E. Yan, Environmental Science Division, Argonne National Laboratory, December 2011. [*Microsoft Word - Drought Analysis Report Final (anl.gov)]
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3. Stocker T F, Dahe Q and Plattner G-K 2013 Technical summary Intergov. Panel Clim. Chang. Phys. Sci. Basis
4. David J. Sailor, Michael Smith, Melissa Hart, Climate change implications for wind power resources in the Northwest United States, Renewable Energy, Volume 33, Issue 11, 2008, Pages 2393-2406, ISSN 0960-1481, https://doi.org/10.1016/j.renene.2008.01.007.
5. Wild M, Folini D, Henschel F, Fischer N and Müller B 2015 Projections of long-term changes in solar radiation based on CMIP5 climate models and their influence on energy yields of photovoltaic systems Sol. Energy 116 12–24.
6. Bartos, M., Chester, M. Impacts of climate change on electric power supply in the Western United States. Nature Clim Change 5, 748–752 (2015).
7. The Impact of Climate Change on Nuclear Power Supply, Kristin Linnerud, Torben K. Mideksa, Gunnar S. Eskeland: https://www.iaee.org/en/publications/ejarticle.aspx?id=2411\
8. Sinnott Murphy, Fallaw Sowell, Jay Apt, A time-dependent model of generator failures and recoveries captures correlated events and quantifies temperature dependence, Applied Energy, Volume 253, 2019, 113513, ISSN 0306-2619, https://doi.org/10.1016/j.apenergy.2019.113513.
9. N. Lu et al., "Climate Change Impacts on Residential and Commercial Loads in the Western U.S. Grid," in IEEE Transactions on Power Systems, vol. 25, no. 1, pp. 480-488, Feb. 2010, doi: 10.1109/TPWRS.2009.2030387.

 Confidential

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FINAL LOAD FORECAST

AMBER RITER / SHANNON GREENE

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Load Forecast Update

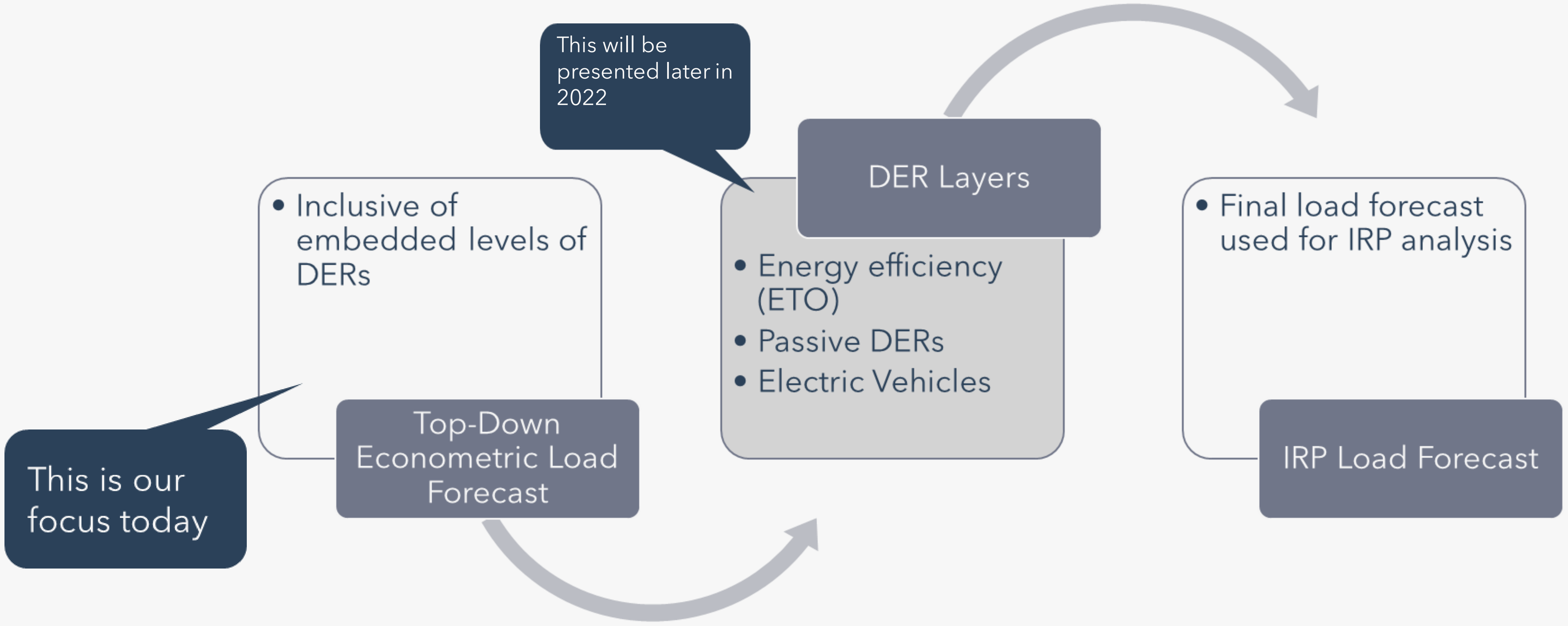
In October 2020, we provided an update on how COVID-19 was impacting PGE's energy deliveries and the short-term load forecast models.

In July 2021, we presented details underlying the load forecast methodology including preliminary long-term and peak demand model specifications and economic scenarios.

Today, we will provide:

- an **overview** of PGE's load forecast methodology;
- an update on **recent trends**, including the impacts of COVID-19 and industrial growth; and
- the **March load forecast**, including inputs assumptions and resulting base, high and low load forecasts to be used in the 2023 IRP.

PGE'S Load Forecast Model



Top-Down Econometric Load Forecast

Near Term (1-5 Years)

25 regression-based monthly energy deliveries models

Business cycle influences energy deliveries

Individual forecasts ~25 large customers

Explicitly removes incremental energy efficiency

Updated as frequently as every quarter

Long Term (5+ Years)

Convergence to long term growth rates, agnostic to business cycle and specific customer growth

Three aggregated customer class models

Assumes energy efficiency is embedded in growth rates

Growth rates are appended to near term model output

Updated annually, to support IRP

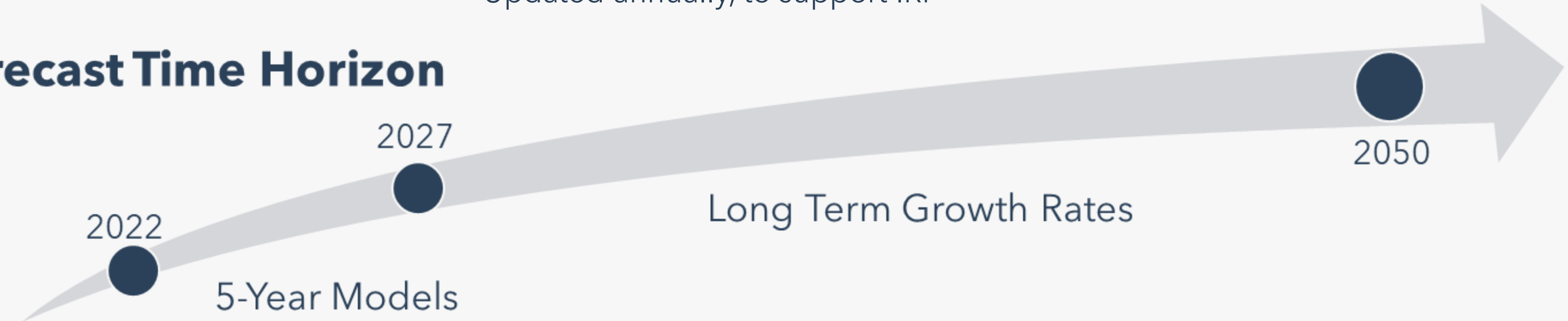
Peak Demand (1+ Year)

Model spans full time horizon, near term and long term

Average energy is a model input

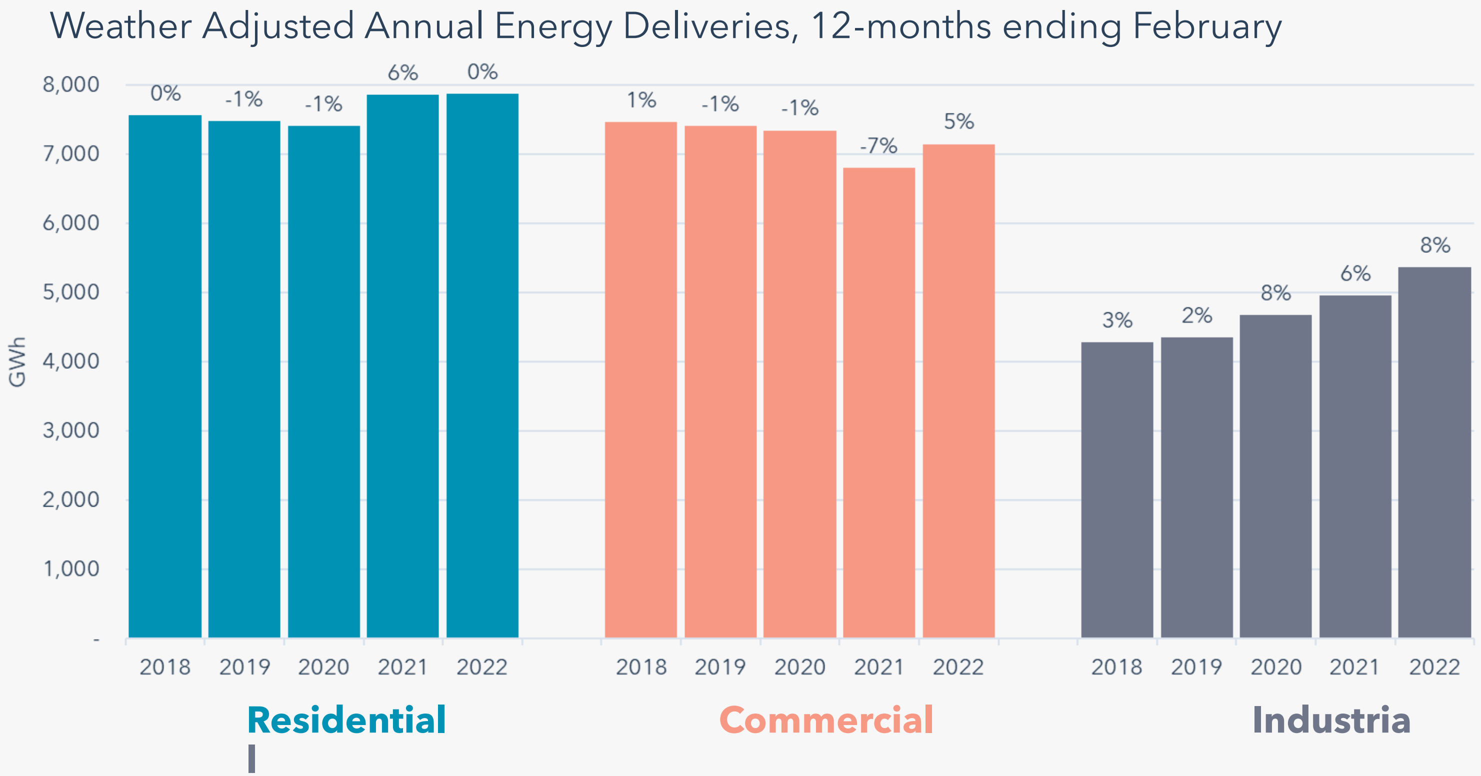
Updated annually

Forecast Time Horizon



Recent Energy Deliveries Trends

- COVID-19 changed how we use electricity.
  - Significant increase in residential usage, largely unchanged in year 2
  - Dramatic decrease in commercial usage, largely recovered in year 2
- Industrial growth has accelerated, reflecting expansion focused in the high-tech segment.
- Recent trends impact the near-term forecast, which is the starting point for the long-term forecast.



Final Long Term Growth Rates

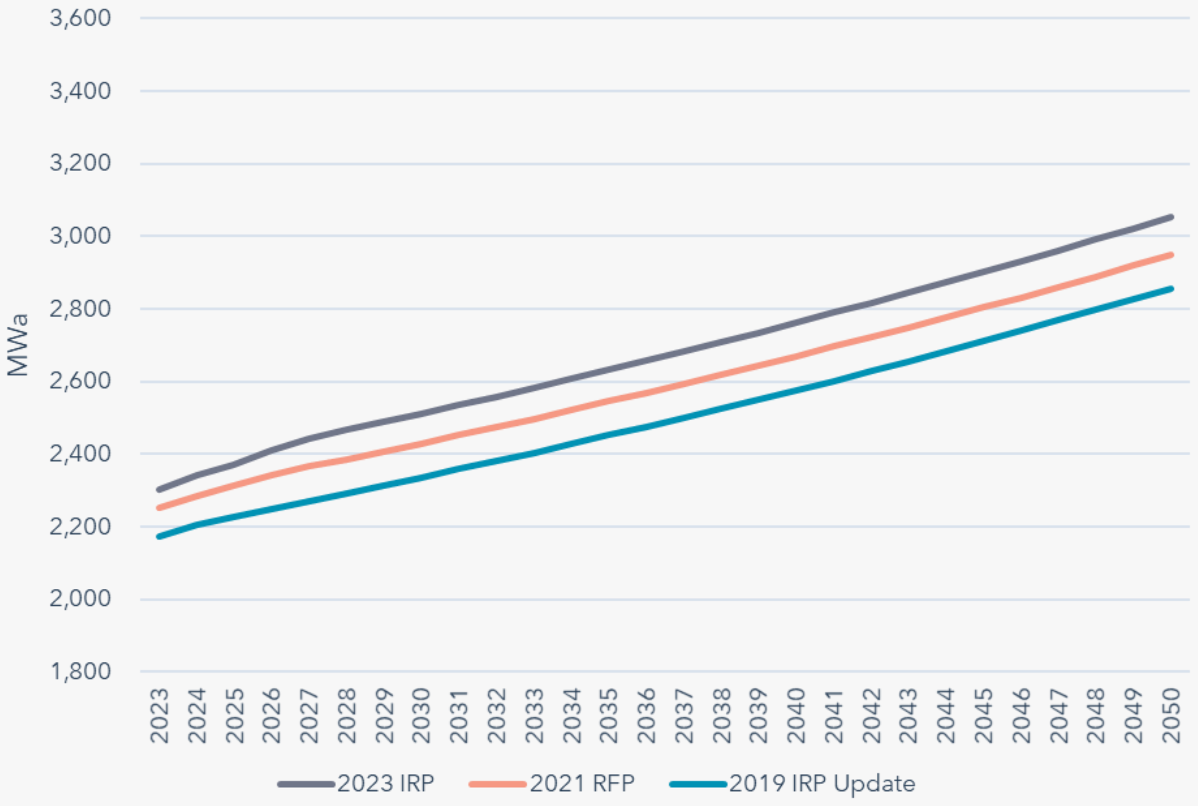
- No structural changes were made to models presented during the July 2021 preliminary results roundtable.
- The economic inputs were refreshed to reflect the latest forecasts.
- Updates in growth rates are driven by updates to the economic forecasts.

Economic Inputs						
	Oregon Population		Oregon Non-Farm Employment		Oregon Personal Income	
Data Source	Oregon Office of Economic Analysis				Woods and Pool	
Vintage	2021	2022	2021	2022	2020	2021
Average Annual Growth 2023-2030	0.8%	0.7%	1.5%	1.3%	1.4%	2.1%
Resulting Top-Down Long-Term Growth Rates						
	Residential		Commercial		Industrial	
Vintage	Prelim	Final	Prelim	Final	Prelim	Final
Annual Average Growth Rate	0.8%	0.7%	0.2%	0.2%	1.9%	2.0%

Forecasted Long Term Energy*

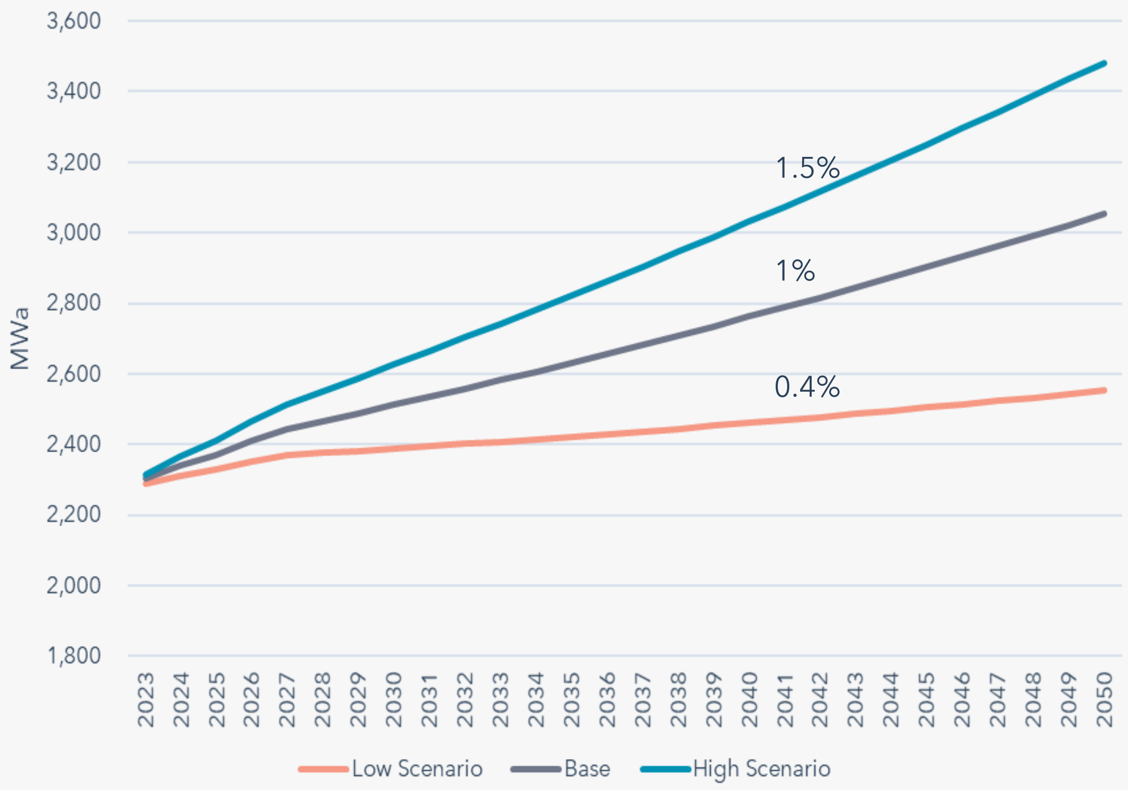
- Sector level long term growth rates have shifted with changing economic conditions.
- Total average long term growth rate has remained consistent at around 1%.
  - ⑩ In the near-term, rapid industrial growth leads to higher annual growth rates
- Recent growth and increases in the near-term forecast result in a level shift in projected usage.

*This summary does not include the estimated energy impact of DERs



Load Forecast Scenarios

Economic Inputs Forecasted Growth Rates			
	Oregon Population Growth	Oregon Non-Farm Employment Growth	Oregon Personal Income Growth
Base case	0.7%	1.3%	2.1%
High growth	1.5%	2.5%	3.5%
Low growth	0.0%	0.5%	1.0%
Resulting Top-Down Long-Term Growth Rates			
	Residential	Commercial	Industrial
Base case	0.7%	0.2%	2.0%
High growth	1.2%	0.5%	3.1%
Low growth	0.3%	-0.2%	0.7%



Final Peak Demand Model

- No structural changes were made to models presented at the July 2021 Roundtable.
- Peak is estimated as a function of average energy, so changes in the energy forecast are reflected in the peak demand forecast.
  - Growth rate of 0.8%
- The 15-year average temperature has been updated to reflect 2007-2021.
  - Summer peak daily average temp of 83.1°F (or max of ~100°F)
  - Winter peak daily average temp of 28.7°F (or min of ~24°F)

RPS MODELING

ROB CAMPBELL

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RPS Modeling in 2019 IRP

- Our portfolio expansion model ROSE-E developed capacity expansion pathways that minimized costs while ensuring resource adequacy and RPS compliance.

- RPS compliance was enforced through a Renewable Energy Certificate (REC) constraint.
    - ROSE-E simulated energy production (from which RECs were generated), banked, and retired based on rules about both five-year and infinite-life RECs.

- Ensured PGE complied with RPS requirements for generation from qualifying sources by selecting pathways that build sufficient renewable energy generation.
    - If yearly REC generation was less than the year's RPS obligation, ROSE-E would build more RPS resources.
    - Both the size of our REC bank and the quantity of incremental RPS resources in the 2019 IRP made this rare.

RPS Modeling in 2023 IRP

- **HB 2021** CO_2 emissions requirements are more stringent than RPS.

Year	**RPS** (% of Retail Sales)	**HB 2021** (% Reduction in CO_2 Emissions)
2030	35%	80%
2035	45%	90%
2040	50%	100% CO_2-Free

- ROSE-E's RPS constraints are now even less likely to be binding in portfolio modeling.
  - Renewable resource additions to meet HB 2021 requirements will exceed amount needed to meet RPS requirements.
- However, the RPS constraints do have a computational cost.

2023 IRP Portfolio Modeling

- CO_2 emissions will be constrained to comply with HB 2021.
- We plan to remove REC constraint from ROSE-E.
    - Reduce computational intensity and processing time
- We will have a full RPS accounting of the preferred portfolio.
- This will have no impact on incremental renewable resource additions.
- This change will not affect compliance filings (RPS compliance report, RPIP).

PRICE UPDATE

SILVIA MELCHIORRI

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PGE

Electricity Price Forecast: Final

Recap – PGE proposed methodology and comparison with previous IRP was presented in:

- Roundtable 21-1 in February 2021,
- Roundtable 21-3 in May 2021, and
- Roundtable 21-8 in November 2021.

PGE web site: https://portlandgeneral.com/about/who-we-are/resource-planning/irp-public-meetings

Goal – Simulate long-term electricity prices for the Pacific Northwest.
We use Wood Mackenzie (WM) data with Aurora software to simulate WECC-wide prices.
Then, we input such prices in PGE-PZM Aurora model for PGE portfolio dispatch.

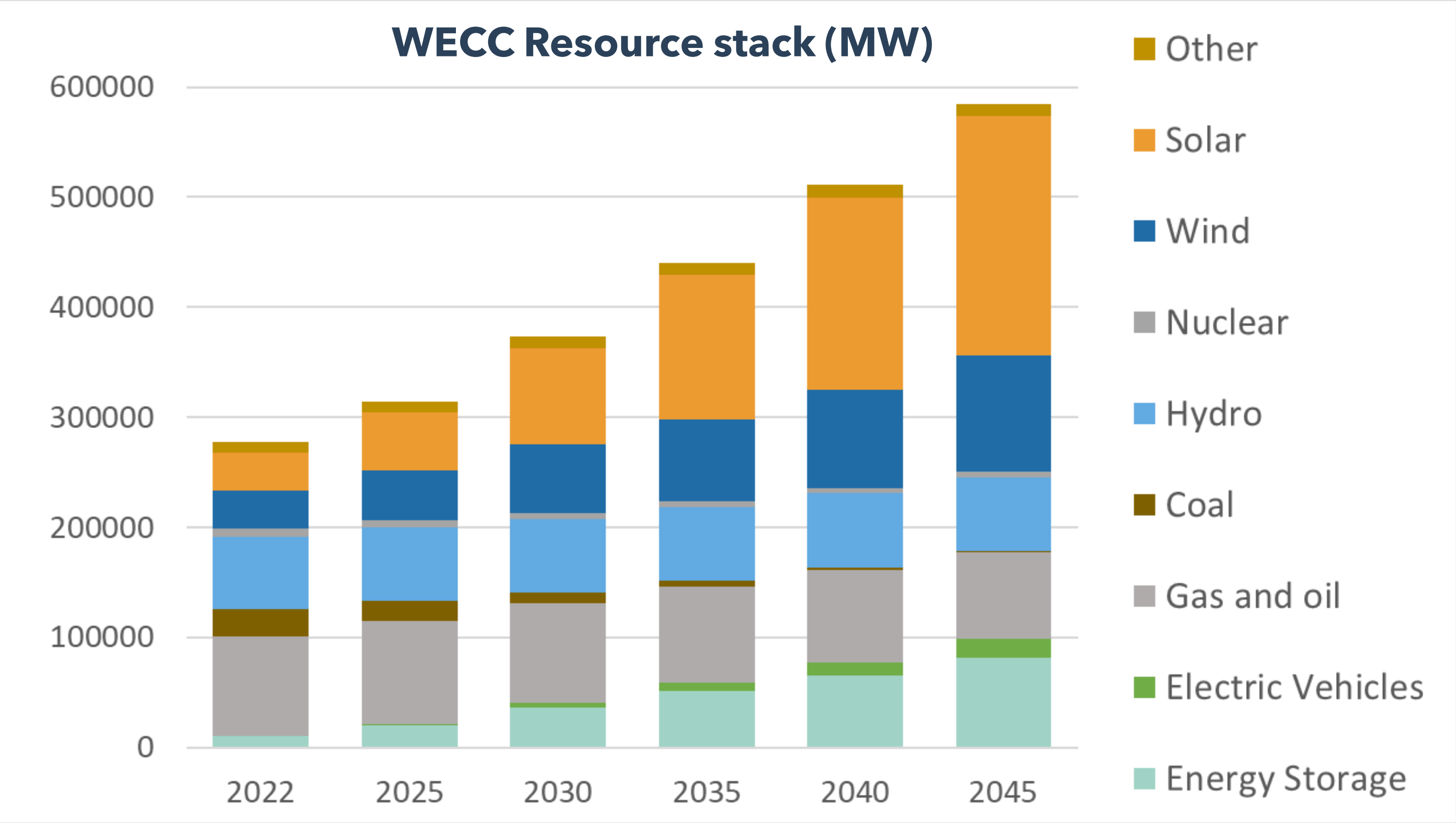
✓ *Reference WECC Database*	✓ *PGE Updates*	✓ *WECC-wide price simulations* **1Q22**	*Input prices for PGE Portfolio Analysis* **Now**

Today's agenda:

1) Show final prices and futures

WECC Model: Setup
High Renewable + Storage Build Out

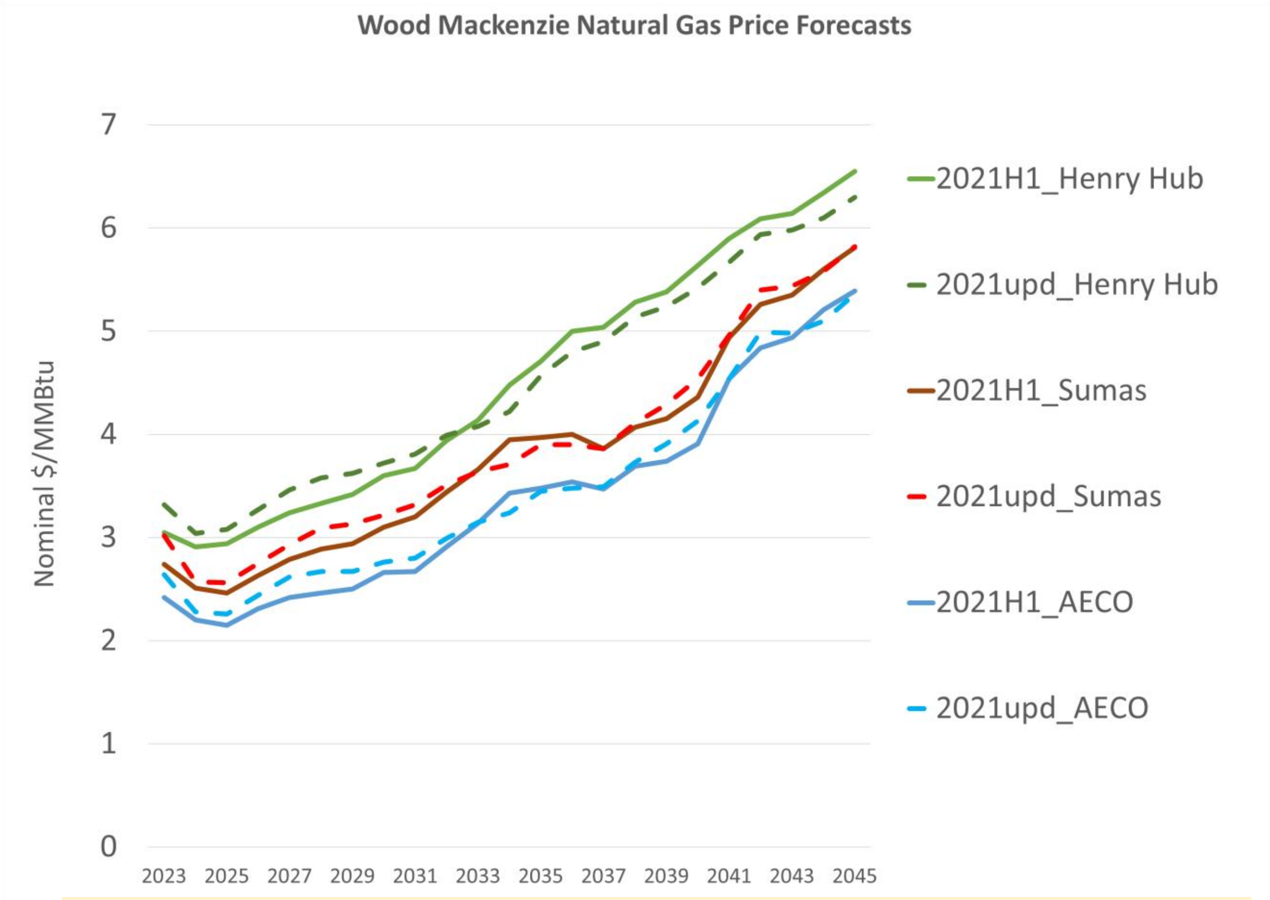
- Aurora + Wood Mackenzie Input DB (WM 2020H2)
- WECC additions are mainly renewables + storage.
- Coal plants are progressively retired.
- Older, less efficient, oil and gas plants are also retired starting in the 2030s.



These charts were obtained from the North America Power & Renewables Service &Tool – WECC, a product of Wood Mackenzie.

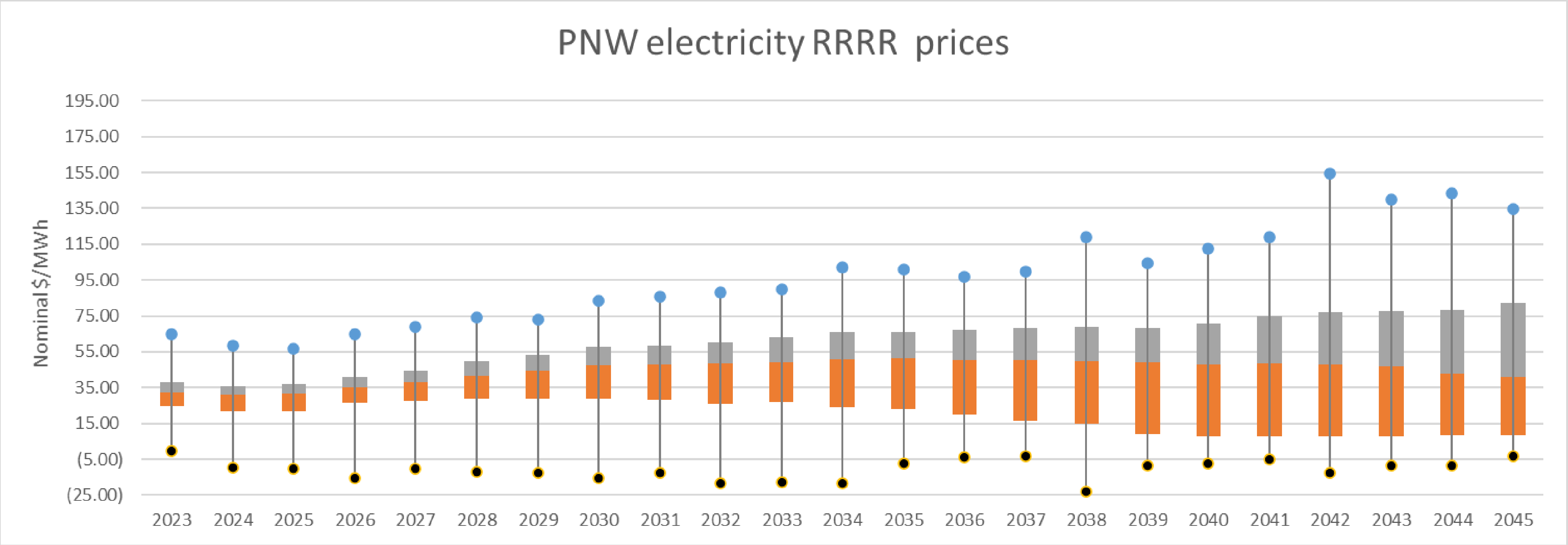
WECC Model Updates:
No Updates Since Last Roundtable

- Gas price forecast: most recent forecast (2021update) is very similar to what shown last November.
- We kept the 2021 base forecast (gas price forecast not updated as change is minor).
- Long-term impact of current shock in the international natural gas market at this point is unknown and not embedded in anybody's long-term forecast.



These charts were obtained from the North America Power & Renewables Service &Tool – WECC, a product of Wood Mackenzie.

WECC Model Results:
Reference Hourly Price Range: 2023-2045



List of Simulated Electricity Price Futures

Risk driver	How we proxy it
Commodity	Natural gas price: 1. Reference: PGE TC + Wood Mackenzie fundamentals 2. Low: estimate of historical minimum prices 3. High: EIA highest price forecast (from Annual Energy Outlook 2021) Hydro: 1. Reference 2. -10% in PNW 3. +10% in PNW
Carbon	Range of carbon adders: 1. Reference: California cap and trade projected prices for California, OR, WA 2. Low: low California price projection 3. High: Social cost with discount rate = 2.5% 4. No carbon adder, proxy for a future where tax credits might be used instead of carbon adders
Uncertainty	Modeled errors in the Aurora Gurobi-optized logic to simulate less-than-perfect commitment (proxy for lacking capacity at the right time): 1. Wind error + ref gas + ref hydro + ref carbon. Imposed price cap of $250/MWh 2. Wind error + high gas + Low hydro + ref carbon. Imposed price cap of $250/MWh
Scarcity	Scarcity premiums affecting prices. No easy way of doing this. Proxied it with: 1. Add start-up costs to on-peak hours. Future: Start-up cost + ref gas + ref hydro + ref carbon

Price Futures Combos

PGE generated the following price futures:

27 combos of gas prices, carbon goals/policy, hydro conditions with default DB setup

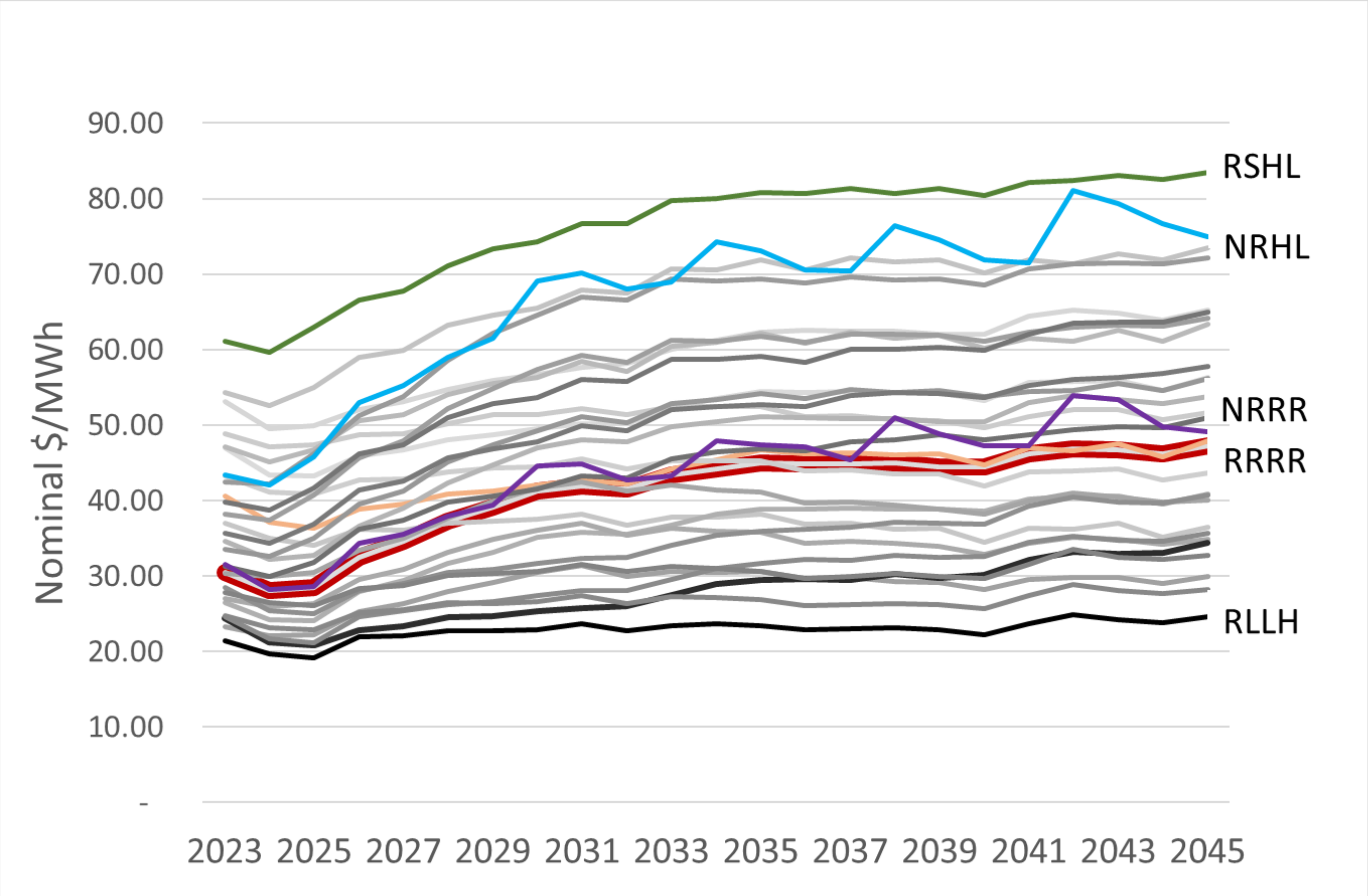
3 futures are then simulated to capture uncertainty and scarcity due to intermittency of generation

1 future with reference gas and hydro but no additional carbon adder in WECC

Futures are identified by the following 4 letter combo:

Variable >>	Aurora setup	Carbon adder	Natural Gas Price	PNW hydro gen
	N Net load commit error	L CA cap and trade LOW for CA, OR and WA. Default for rest WECC.	H EIA-AEO 2021 highest gas price case	H +10% PNW hydro generation
	R Wood Mackenzie default	N No carbon adder in dispatch	L PGE estimate of Low historical gas	L -10% PNW hydro generation
	S Start up cost added to prices	R CA cap and trade REF for CA, OR and WA. Default for rest WECC.	R Wood Mackenzie default	R Wood Mackenzie default
		S Social Cost 2.5% discount rate for CA, OR and WA. Default for rest WECC.		
Example future:	R Wood Mackenzie default	R CA cap and trade REF for CA, OR and WA. Default for rest WECC.	R Wood Mackenzie default	R Wood Mackenzie default

PNW Price Range Across Futures: Detail



Example future:

R	Wood Mackenzie default	R	CA cap and trade REF for CA, OR and WA. Default for rest WECC.	R	Wood Mackenzie default	R	Wood Mackenzie default

QUESTIONS/ DISCUSSION?

STAKEHOLDER FEEDBACK

We want your feedback

If you'd like to provide feedback on PGE's 2023 IRP or the IRP process, fill out our form.

portlandgeneral.com/irp

NEXT STEPS

Upcoming Roundtables:

May 19

June 30

July 21

August 18

September 15

October 20

November 16

December 15





THANK YOU

CONTACT US AT:
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